SECTION 6A – INJECTION WELL MONITORING, INTEGRITY TESTING, AND CONTINGENCY PLAN

This section is intended to satisfy the requirements of 40 CFR 146.90.

6A.1 Fluid Sampling and Analysis of the CO_2 Injectate

6A.1.1 Sampling Frequency

As detailed in Section 7 of this application, the injection stream (injectate) is high purity CO_2 with trace levels of other constituents. The CO_2 vent stream from biofuel fermentation is relatively consistent with respect to composition and mass due to the nature of the process and also a result of the operation of the vent scrubber system to remove volatile organic compounds. The scrubber system operates within established parameters in accordance with air permitting requirements. Based on these stream characteristics, quarterly sampling of the CO_2 is proposed.

6A.1.2 Analysis Parameters

Each sample will be analyzed for the parameters listed in Appendix E – Material Analysis Plan.

Unlike captured CO_2 from the combustion of fossil fuels, the ADM CO_2 stream produced from the ethanol plant is very pure. The parameters were selected based on the typical impurity profile for CO_2 produced during the anaerobic fermentation of sugars to ethanol. These parameters and the monitoring process are intended to ensure that the CO_2 stream does qualify as hazardous waste or pose a corrosion risk to the facility's materials of construction. Methods to measure the composition of the CO_2 stream will conform to applicable chemical analytical standards like ASTM standard E1747-95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications.

6A.1.2.1 CO_2 Corrosivity

A water saturated CO_2 stream can be corrosive to carbon steel as reported by Dugstad, Lunde, and Nesic (1994). Therefore the metallurgy used prior to the gas dehydration unit is 316SS which is resistant to CO_2 corrosion as reported by Bruce D. Craig and Liane Smith (2011).

The gas dehydration unit will reduce the water content of the CO_2 to a range of 7 to 30 lb of H_2O/MMSCF (150 to 630 ppmv H2O). This water content range is consistent with typical U.S. CO_2 transmission pipeline water content specifications for carbon steel pipe, therefore, no corrosive reactions are anticipated. An online water analyzer using tunable diode laser absorption spectroscopy will be employed downstream of the dehydration unit to monitor the water content of the injectate.

Additionally the project will employ a corrosion monitoring plan in order to monitor the corrosion potential of materials that will come in contact with the carbon dioxide stream. This plan is detailed in section 6A.3.5 of the application.

6A.1.2.2 CO_2 Toxicity

Carbon dioxide gas is an asphyxiant with effects due to lack of oxygen. It is also physiologically active, affecting circulation and breathing. CO_2 has the following exposure limits:

OSHA PEL = 5,000 ppm
ACGIH TLV-TWA (2007) = 30,000 ppm 15 min STEL
IDLH = 40,000 ppm
LC_{Lo} = 90,000 ppm, 5 min., human

Installation of CO_2 atmospheric monitors will be employed within the compression facility and the storage site to alert operations personnel about elevated levels of CO_2 in excess of OSHA personnel exposure limits.

A material safety data sheet for CO_2 is presented in Appendix E.

6A.1.3 Sampling Location

Sampling will be conducted downstream of the vent scrubber. The locations and details of the sample points are undetermined. The finalized sample point design and locations will be included in the well completion report.

6A.1.4 Detailed Injectate Fluid Analysis Plan

A detailed injectate material analysis plan is included as Appendix E.

Methods to measure the composition of the CO2 stream will conform to applicable chemical analytical standards and may include ASTM standard E1747-95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications.

6A.2 Monitoring Program

The permit holder will use the site infrastructure employing methods to achieve the UIC Class VI program's objectives and requirements in the following categories:

- Mechanical Integrity Tests
- Operational Testing and Monitoring
- Plume and Pressure-Front Tracking
- Ground Water Quality and Geochemistry Monitoring
- Soil Gas and Surface Air Monitoring

The comprehensive program focuses on ensuring that the subsurface zones above the confining zone are not compromised by the injection and storage of CO_2 within the Mt. Simon Sandstone. To meet the goals of the program, the subsurface monitoring program focuses on four zones:

1. Pleistocene and Pennsylvanian sands – the source of local drinking water.
2. The St. Peter Sandstone – the lowermost underground source of drinking water.
3. The Ironton-Galesville Sandstone – the zone above the confining Eau Claire cap rock.
4. The Mt. Simon Sandstone – the injection and storage zone.

Appendix F details the monitoring program developed for each of these zones.

The monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone.

In addition to monitoring at the injection well (CCS#2), the operator will drill and complete one observation well (Verification Well #2) that penetrates the Mt. Simon Sandstone in order to provide another injection zone monitoring point. Other site monitoring includes the use of a shallower observation well to be named Geophysical Monitor #2 (GM#2). Details on the monitoring techniques used in these observation wells are described in Sections 6B and 3C, respectively. A summary of the sites various wells and their capabilities is shown in Table 6A-1. This summary includes the wells already employed by the Illinois Basin Decatur Project (IBDP). The infrastructure and data from both projects will be integrated to provide a comprehensive site monitoring program.

Table 6A-1: ADM Decatur Site Monitoring Infrastructure

	IL ICCS Wells			IBDP Wells		
	CCS #2	VW #2	GM #2	CCS#1	VW #1	GM #1
Approx. Depth (ft)	7200	7200	3500	7200	7200	3500
Approx. Distance from CCS#2 (ft)	0	2600	100	3700	2800	3800
Capable of obtaining:						
Mt. Simon pressure(s)/temperature(s)	yes	yes	no	yes	yes	no
Mt. Simon fluid sampling	no	yes	no	no	yes	no
Ironton Galesville pressure/temperature	no	no	no	no	yes	no
Ironton Galesville sampling	no	no	no	no	yes	no
St. Peter pressure/temperature	no	no	yes	no	no	no
St. Peter fluid sampling	no	no	yes	no	no	no
RST Logging (near wellbore CO_2 detection)	yes	yes	yes	yes	yes	yes
Seismic Imaging of CO_2 plume	no	no	yes	no	no	yes
Annulus Pressure at surface	yes	yes	yes	yes	yes	yes
Injection Pressure at surface	yes	no	no	yes	no	no

* Deeper formations only. Shallow USDW monitoring not included in this table

Monitoring at the injection well will include annual surveys which are described in Section 6A.3.2. Details about the continuous operational monitoring are described below.

6A.2.1 Recording Devices

All essential monitoring, recording, and control devices will be functional prior to injection operations. Essential operational monitoring will be continuous and includes: injection flow rate and volume, well head injection pressure, well head injection temperature, and well head casing annulus pressure. A description of the surface facility equipment and control system is presented in section 6A.2.2.3 of this application. Regarding the annular pressure, monitoring this parameter will provide the information necessary to determine whether there is a failure of the casing-cement bond, injection tubing, and/or down hole isolation devices - packers. A description of the continuous annular pressure monitoring system is presented in section 6A.3.1 of this application. Regarding the injectate, the CO_2 is a dry supercritical fluid, therefore no pH recording devices are warranted; however an online water analyzer using tunable diode laser absorption spectroscopy will be employed downstream of the dehydration unit to monitor the water content of the injectate. Additionally, corrosion coupons will be installed to indirectly monitor corrosion on the process piping and equipment. This plan is fully described in Section 6A.3.5 - Corrosion Monitoring Plan.

6A.2.2 Control and Alarm System for the Well Monitoring and Maintenance

Alarms and shutdown systems will be installed and functional prior to injection operations. In order to meet the permit requirements, alarm and shutdowns systems will be initiated for deviations on essential operating parameters. These parameters include injection flow rate and volume, well head injection pressure, and well head casing annulus pressure. During shutdown events, the master control and monitoring system will be programmed to take the appropriate action for each specific event in order to safeguard the facility. Actions may include but are not limited to wellhead isolation, pipeline isolation, system venting (de-pressuring), and process equipment shutdown. Table 6A-2 lists the essential surface injection operating parameters. A description of the surface facility equipment and control system is presented in section 6A.2.2.3 of this application. A description of the continuous annular pressure monitoring system is presented in section 6A.3.1 of this application.

Table 6A-2: Surface injection operating parameters.

Surface Injection Parameter	**Operating Range**
CO_2 Injection Flow Rate	Up to 3,300 metric tons/day
Flow Rate Variation	+/- 10% of flow rate set point
Wellhead Inlet Pressure	< 2,380 psig
Annulus pressure at surface	> 500 psig

6A.2.2.1 Control System Overview

The surface facility's process flow diagrams (PFDs), which include the compression, dehydration, and transmission equipment, are provided in Section 4 – Injection Well Operation, while the piping & instrument diagrams (P&IDs) for these facilities can be found in Appendix C. These diagrams detail the facility's equipment, configuration, instrumentation, surveillance, and control systems. A process narrative describing the facility's equipment and control equipment is presented in Section 6A.2.2.3 – Surface Facility Equipment & Control System Description.

6A.2.2.2 Wellbore and Wellhead Design

The design of the injection well includes but is not limited to the following:

1. A dual master and single wing Xmas tree assembly with a swab valve above flow tee. Upper master will have an automatic shutoff capability. Wing valve will have an automatic valve (current design calls for a check valve) installed directly upstream of the wing valve to prevent backflow into the pipeline.

2. All annuli will have pressure gauges and sensors to detect any abnormal pressure spikes.

3. Injection pressures will be monitored and recorded at the compressor discharge and at the wellhead. Additionally, the pressure of the wellhead casing annulus will be monitored and recorded.

4. Along with continuous, real time recording and automatic shut-down systems, field operations personnel will perform daily rounds and routine inspections of the compression, dehydration, and transmission facilities as well as the well sites to ensure the integrity of the surface systems and apparent functionality of mechanical equipment.

5. All Xmas tree equipment is rated to at least 3,000 psig working pressure, plus the Xmas tree assembly (upper valve assembly) is constructed of stainless steel and/or chrome. Based on expected bottomhole pressures and other well controls and limitations, we will not exceed the working pressure of the 3,000 psi well head in any application or under any operating conditions. The maximum calculated injection pressure is 2,380 psig.

6. Normal operating pressure at the wellhead will be 2,380 psig or less. Alarms will be set at 2,350 psig and automatic shutdown will occur at 2,380 psig. Maximum surface injection pressure at the wellhead will be 2,380 psig.

The operating range of surface facilities instruments will address the minimum and maximum expected operating conditions for each instrument (surface pressure gauges, temperature gauge, annulus pressure gauges, etc.). The instruments will include an operating range that is at least 20% outside the expected maximum and (if required) minimum operating range.

If communication (and subsequent data archiving) is lost for any reason with any portion of the monitoring system, an investigation will immediately be conducted to determine the cause, and actions taken to restore communications. Injection will be shut down only under certain circumstances (reference the contingency plan in Section 6A.4). In the special case of wellhead surface pressure and annulus pressure, if communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every four hours for both parameters and record the data until communication is restored. An example of a form for maintaining the record is included in Figure 6A-1.

Figure 6A-1: Example Field Log Form for Manual Injection Well Gauge Readings

FIELD LOG – INJECTION / VERIFICATION WELLS
(For back up field data collection in the event of power outage or other data transmission loss from automated gauges – see "*Instructions"*)

Illinois EPA Site #1150155136 – Macon County Archer Daniels Midland – Corn Processing Carbon Sequestration Injection and Verification Wells	Permit No. Well No. UIC Log #

ADM Supervisor: ____
Readings Taken by: Name:____
Phone:____

Check Box(es) Above Failed Instrument(s) ➔						
DATE	**TIME**	**Injection Wellhead Pressure** PIT-009 (psig)	**Injection Annulus Pressure** PIT-014 (psig)	**Verification Tubing Pressure** Westbay (psig)	**Verification Annulus Pressure** Westbay (psig)	**INITIALS**

***INSTRUCTIONS –** Within 30 minutes of a communication loss, manual readings of the pressure in the tubing and annulus of both wells will be taken and recorded, and continued every 4 hours thereafter until communication is restored.*

6A.2.2.3 Surface Facility Equipment & Control System Description

The description of the equipment and operating controls for the Surface Facilities is as follows (reference Piping & Instrument Diagrams (P&IDs) in Appendix C):

Collection and Blower Area

The P&IDs detail the surface facility's equipment, configuration, instrumentation, surveillance, and control systems. The compression train receives the low pressure (~0.5 psig) CO_2 from the primary CO_2 scrubber's overhead, gas outlet, line. From the scrubber, the CO_2 gas stream is sent to the blower inlet separators, TK-501/2, where condensed liquid, mainly free water carried over from the scrubber, is removed. The water level in the separators is controlled via start/stop of the inlet separators water pumps through level transmitters/controller LT-501/2. The pressure (PTX-501A/2A) and temperature (TIT-501A/2A) of the separators overhead CO_2 gas stream are measured before the stream enters the blowers, BL-501/2, where the CO_2 pressure is increased by approximately 16 psi. The blower outlet temperature and pressure are monitored and alarmed by TIT-501B/2B and PTX-501B/2B. At this point, the CO_2 stream is monitored for oxygen by an online gas analyzer ARX- 001. A high oxygen reading may indicate an air leak or instrument failure that would allow air into the system through a flange leak or through the CO_2 scrubber's vent stack. In the event of high oxygen alarm, the operational staff would initiate steps to determine the source of the alarm condition and to take corrective action. After compression, the gas stream is cooled by the blower aftercooler exchanger, HE-501. The cooler outlet gas temperature is measured by TIT-503A and controlled at a set point (95°F) via TCV-503A; located on the exchanger's cooling water return line. The exchanger's cooling water inlet and outlet conditions are indicated by TI-502/3 and PI-503.

Next, the CO_2 stream enters the blower after cooler separator, TK-503, where any condensed liquid is removed. The water inventory in TK-503 is controlled by level controller LIC-502 via control valve LCV-502. The blower's discharge stream pressure is controlled by PTX-502B via variable frequency drive, VFD-502, controlling the blower motor, BLM-503. This control system is not shown on the enclosed PIDs but will be detailed on the finalized construction PIDs and included with the well completion report. Additional high pressure control is provided by PIC-502 located on TK-503's overhead gas outlet line which safely vents the CO_2 to atmosphere via control valve PCV-502. After cooling and water removal, the CO_2 stream is transported to the main compression building through 1,500 feet of 24" line. At the compression building, the CO_2 stream is split and enters the suction of four reciprocating compressors, K-600/700/800/900. Each compressor operates in parallel and is a six throw (cylinder) machine with 4-stages of compression.

Main Compression Area – Stages 1-3

During CO_2 compression, each stage follows a sequence of free liquid removal, pulsation dampening, compression, pulsation dampening, and cooling before moving to the next compression stage. The following paragraph provides a process narrative for K-600. The other compressors will have identical equipment and control elements.

In the 1st stage of compression, the CO_2 stream enters the 1st stage scrubber, SR-601, where any free liquid is removed. The scrubber level is controlled by LIC-601 via control valve LCV-601. The compressor's feed stream conditions (suction side) are indicated and alarmed by TIT-601A and PTX-601A. After liquid knock out, the CO_2 stream passes through the 1^{st} stage suction (pulsation) bottle, K-601A, before being compressed in cylinders #1 and #3. In this stage, the gas is compressed to 75 psia, after which it passes through the 1^{st} stage discharge (pulsation) bottle, K-601B. High compressor discharge temperature is monitored and alarmed by TIT-601B/C. Pressure safety valves, PSV-601C/D, provide over pressure protection on the compressor discharge. Next, the gas is cooled to 95°F by the 1^{st} stage intercooler, HE-601, before moving to the 2^{nd} stage of compression.

In the 2^{nd} stage, the CO_2 stream passes through the 2^{nd} stage scrubber, SR-602, where any free liquid is removed. The scrubber level is controlled by LIC-602 via control valve LCV-602. The 2^{nd} stage suction conditions are indicated and alarmed by TIT-602A and PTX-602A. After liquid knock out, the CO_2 stream passes through the 2^{nd} stage suction bottle, K-602A, before compression to 249 psia in cylinders #2 and #4. The compressor discharge temperature is monitored and alarmed by TIT-602B/C. Pressure safety valves, PSV-601A/B, provide over pressure protection on the compressor discharge. Next the compressed CO_2 stream passes through the 2^{nd} stage discharge bottle, K-602B, and is cooled to 95°F in the 2^{nd} stage intercooler, HE-602, before moving to the 3^{rd} compression stage.

In the 3^{rd} compression stage, the CO_2 stream enters the 3^{rd} stage suction scrubber, SR-603, where free liquid is removed. The scrubber level is controlled by LIC-603 via control valve LCV-603. The 3^{rd} stage suction conditions are monitored and alarmed by TIT-603A and PTX-603A. After liquid removal, the CO_2 stream passes through the 3^{rd} stage suction bottle, K-603A, followed by compression to 598 psia in cylinder #6, before traveling through the 3^{rd} stage discharge bottle, K-603B. The compressor discharge temperature is monitored and alarmed by TIT-603B/C. Pressure safety valves, PSV-603A/B, provide over pressure protection on the compressor discharge. Next, the gas is cooled to 95°F by the 3^{rd} stage intercooler, HE-603, before further processing.

Dehydration Area

At this point in the process, 95% of the water entering with the CO_2 stream has been removed through compression and cooling. After the third stage of compression, the CO_2 stream contains approximately 1300 ppmwt H_2O. Because this exceeds the recommended water content for subsurface injection, the four streams are combined to be sent to the glycol dehydration skid, shown in PD-09/10.

The design basis for the dehydration unit is to remove enough water from the CO_2 stream to insure the exiting stream contains no more than 30 lbs of H_2O per mmscf of CO_2, approximately 265 ppmwt H_2O. Dehydration with tri-ethylene glycol (TEG) typically produces a CO_2 stream with a water content of less than 7 lbs per mmscf of CO_2 (60 ppmwt H_2O). Based on an inlet feed gas composition of 151 lbs H_2O/mmscf, the unit's water removal capacity is 173 lbs/hr yielding a final CO_2 stream with water content of 11 lbs H_2O per mmscf CO_2 (60 ppmwt H_2O).

After the 3^{rd} compression stage, the four streams are combined and enter the dehydration inlet separator, TK-751, where any free liquid is removed. After liquid removal, the gas stream enters the bottom of the TEG glycol contactor, VS-751, where it is contacted with lean (water-free) glycol introduced at the top of the contactor. The glycol removes water from the CO_2 by physical absorption and the rich glycol (water saturated) exits the bottom of the column. The dry CO_2 stream leaves the top of the contactor and passes through the glycol heat exchanger, HE-

751, where the gas is cooled to 95°F, via cross exchange with lean glycol, before returning to the compression section.

Regarding the rich glycol stream, after leaving the contactor it is cross exchanged with the regenerator O/H vapor stream in the reflux condenser coil in the top of the glycol still, VS-752. Next this stream is further heated by cross exchange with the regenerator bottoms (lean glycol) stream in the cold glycol exchanger, HE-752. Next the stream enters the glycol flash tank, TK-752, where any non-condensable vapors are removed by venting through PCV-751.

After leaving the flash vessel, the glycol is filtered and polished by FR-754A/B, glycol solids filter, and FR-755A/B, rich glycol carbon filter. Next, additional heating of the rich glycol occurs by cross-exchange with the regenerator bottoms (lean glycol) in the hot glycol exchanger, HE-753, before entering the glycol still column, VS-752. The glycol regeneration equipment consists of a column, an overhead condenser coil, and a reboiler, HE-755. In the still column, the glycol is thermally regenerated via hot vapor stripping the water from the liquid phase.

The hot lean glycol exits the bottom of the tower and enters the reboiler where it is heated and any remaining water is flashed into vapor (steam). The steam returns to the bottom of the tower where it acts as the striping agent removing water from the rich glycol descending the still. Excess lean glycol in the reboiler flows over a level weir and enters a glycol surge tank. Next the hot lean glycol gravity flows through the previously described cross exchangers (HE-752/753) where it is cooled by the rich glycol. Finally the glycol pumps, PU-752A/B pressurizes the lean glycol, after which it is cooled through cross exchange with dry CO_2 in HE-751, and returns to the top of the glycol contactor, VS-751, starting another process cycle.

After dehydration the CO_2 stream is monitored and alarmed for water content by gas analyzer ARX-006 (see PD-21), after which the stream is split and returned to the four compressors 4th stage.

<u>Main Compression Area – Stage 4 and Booster Pumps</u>
As with the previous compression stages, the CO_2 stream enters the 4th stage suction scrubber, SR-604, where any free liquid is removed. The scrubber level is controlled by LIC-604 via control valve LCV-604. The compressor's feed stream conditions (suction side) are indicated and alarmed by TIT-604A and PTX-604A. After liquid knock out, the CO_2 stream passes through the 4th stage suction (pulsation) bottle, K-604A, before being compressed in cylinder #5. In this stage, the gas is compressed to 1425 psia, after which it passes through the 4th stage discharge (pulsation) bottle, K-601B. High compressor discharge temperature is monitored and alarmed by TIT-601B/C. Next, the gas is cooled to 95°F by the 4th stage aftercooler, HE-704A/B, before further compression. The compressor's discharge pressure control is accomplished by PIC-604C via PCV-604C, which recycles gas to the 1st stage scrubber, SR-601. Additional high pressure control is provided by pressure relief valve PSV-604A/B, which safely vents the stream to atmosphere.

After cooling, the CO_2 streams are combined and sent to the CO_2 multistage centrifugal pumps, PU-754A/B/C. Here the CO_2 stream is in a dense phase and is compressed to 2,565 psia and transported to the injection well by 5,000 feet of 8" pipeline. Flow to the wellhead is monitored by flow indicating transmitter FIT-006 and is controlled by flow controller FC-006 by changing the set point on the pump's variable frequency drive, VFD-754A/B/C. Additionally a pressure indicating transmitter, PIT-007 will provide a high pressure protection by allowing the pressure transmitter to reset the flow. The final high pressure control is provided on the pump discharge by pressure relief valves PSV-082/083/084(A/B), which safely vent the stream to atmosphere.

Transmission Line and Injection Well

As mentioned previously, the CO_2 stream is transported to the injection well via a 5,000 foot pipeline constructed of 8" schedule 120 carbon steel. The pipeline is equipped with automated block valves NV-023, located at the compressor building (see PD-13), and MOV-023, located at the wellhead (see PD-40), as part of the control system for isolating the pipeline and injection well during a shutdown event. At the injection well site, monitoring and alarm of stream parameters is accomplished with temperature indication TIT-009 and pressure indication PIT-012.

Additional overpressure protection is provided on the pipeline by two spring-operated thermal relief valves, TRV-001 and TRV-002. The purpose of these valves is to relieve pressure resulting from the thermal expansion of the fluid if the pipeline is isolated for a shutdown event.

Master Control and Surveillance System

Regarding the UIC Class VI permit conditions, the control system will limit maximum flow to 3,300 MT/day and/or limit the well head pressure to 2,380 psig, which corresponds to the regulatory requirement to not exceed 90% of the injection zone's fracture pressure. All injection operations will be continuously monitored and controlled by the ADM operations staff using the distributive process control system. This system will continuously monitor, control, record, and will alarm and shutdown if specified control parameters exceed their normal operating range.

The CO_2 compression, transmission, and injection system has a robust control and surveillance structure programmed to identify abnormal operating conditions and/or equipment malfunctions, automatically make the appropriate process response, annunciate the condition to ADM operations personnel staff, and to shut down the process equipment under certain conditions.

More specifically, all critical system parameters, e.g., pressure, temperature, and flow rate will have continuous electronic monitoring with signals transmitted back to a master control system. A list of these instruments, with the instrument description/location, tag number, type of instrument, brand/model number, service, compatibility and operating range information, will be provided within the well completion report. The list will also indicate whether the instrument activates a shutdown of the surface equipment. Real time monitoring for water and oxygen content is also included in the plant design. The recording devices, sensors and gauges will meet or exceed the maximum operating range by 20%.

ADM supervisors and operators will have the capability to monitor the status of the entire system in two locations: the compression control room (near the main compressors), and the main Alcohol Department control room. Should one of the parameters go into an alarm status, the control system logic will automatically make the necessary changes, including shutting down the entire compression system if warranted. At the same time, audible and visual alarms will activate in both the compression control room and the main Alcohol Department control room. Alcohol Department supervision will respond to the alarms, identify the problem, and dispatch the necessary resources to address the problem.

A loss of power to the compression system will shut down surface compression and injection. Automatic shutdown valves NV-023, located at the compressor building, and MOV-023, located at the wellhead, V-347 will automatically isolate the pipeline. Additionally, check valve at the wellhead will prevent the backward flow of CO_2 from the wellhead.

A Hazard and Operability Study (HAZOP) was conducted for the design of the CO_2 compression and dehydration portions of the Surface Facilities. The process nodes evaluated during the HAZOP were blower, reciprocating compression Stages 1, 2, 3 and 4, and the dehydration unit, centrifugal pump, pipeline, and wellhead systems. Engineering and administrative controls were specified for each of the consequences identified during the HAZOP.

6A.2.3 USDW Monitoring in Area of Review

In Macon County, water wells are commonly used as a local source of drinking water. The wells are drilled into the Pleistocene and Pennsylvanian sands. Some water wells are completed in the shallow bedrock, but water quality deteriorates rapidly with depth. Available information shows that sand and gravel deposits are not uniformly distributed throughout the county (Larson et al., 2003, Figure 6A-2) and may not be found continuously beneath the IL-ICCS site. A groundwater monitoring plan has been developed for this zone and is presented in Appendix F1. Most water wells in the AoR have depths ranging from 70 to 101 feet (Figure 6A-3), which coincides with the depth of the upper Glasford Aquifer (Figure 6A-4). Because the Illinois EPA determined that the Pennsylvanian bedrock was the lowermost USDW, the initial application focused the USDW monitoring plan on this zone. However on March 21, 2012, the USEPA made the determination that the St. Peter Sandstone is the lowermost underground source of drinking water within the AoR of this permit application. Therefore, a groundwater monitoring plan has been developed for this zone and is presented in Appendix F2.

6A.2.4 Detailed Groundwater Monitoring Plan

The groundwater monitoring plan focuses on four zones:

1. Pleistocene and Pennsylvanian sands – the source of local drinking water.
2. The St. Peter Formation – the lowermost underground source of drinking water.
3. The Ironton-Galesville Sandstones– the zone above the confining Eau Claire cap rock.
4. The Mt. Simon Sandstone – the injection and storage zone.

Appendix F1 presents the groundwater monitoring program for the Pleistocene and Pennsylvanian aquifers. Because these aquifers are not the lowermost source of drinking water and because this monitoring zone has no significant chance of being compromised by the injection and migration of CO_2 as discussed in Section 6A.2.6.1, the groundwater monitoring program for this zone is deemed voluntary. All data developed by this monitoring plan will be available to the agency upon request. The groundwater monitoring plan presented in Appendix F1 is strictly informational.

Appendix F2 presents the groundwater monitoring plan for the St. Peter Sandstone, the aquifer designated the lowermost source of drinking water (USDW).

Appendix F3 presents the groundwater monitoring plan for the Ironton-Galesville, the saline aquifer directly above the primary seal formation.

Appendix F4 presents the groundwater monitoring plan for the Mt. Simon Sandstone, the injection and storage formation.

6A.2.5 Tracking Extent and Pressure of CO_2 plume

Identification of the position of the injected carbon dioxide plume and the presence or absence of elevated pressure (i.e., the pressure front) is integral to protection of USDWs for Class VI projects. Regions overlying the separate-phase (i.e., liquid, gaseous or supercritical) carbon dioxide plume and area of elevated pressure may be at enhanced risk for fluid leakage that may endanger a USDW. Monitoring the movement of the carbon dioxide and the pressure front is necessary to both identify potential risks to USDWs posed by injection activities and to verify predictions of plume movement. Monitoring results from all of these methodologies can also provide necessary data for comparison to model predictions, and inform reevaluation of the AoR. (USEPA GS_Testing and Monitoring Guidance. Jan 2012)

The proposed methods for Plume and Pressure-Front Tracking for the IL-ICCS project include direct pressure monitoring, reservoir saturation measurements (RST) using pulsed neutron cased hole logging technology, and indirect geophysical monitoring via the use of seismic surveys. The observation wells will be designed and completed to provide capabilities for geochemical monitoring, i.e. fluid sampling. Pre-injection fluid sampling to provide baseline constituent analysis will be performed in the event that the other plume and pressure front tracking measurements or methods indicate a need for subsequent sampling. All site data from the methods mentioned here will be incorporated into a comprehensive mathematical model of the site. ECLIPSE is the tool which will be used. The model will be calibrated using these datasets.

Direct pressure monitoring in the injection well (CCS#2) will be done via pressure gauge installed at surface (at the wellhead). Additionally, a downhole pressure gauge will be located at the packer. These gauges will record the inside tubing pressure and temperature. These pressure measurements will be helpful in monitoring changes in reservoir pressure during the lifetime of the project.

Other in situ pressure measurements of the injection zone will be done in Verification Well #2 (VW#2) and are described in Section 6B. These measurements are intended to show the anticipated buildup of pressure in the lower Mt. Simon injection zone while demonstrating that the upper Mt. Simon remains near the pre-injection pressure. The pressure measurements from Verification Well #1 (VW#1) and GM#2 are anticipated to show that pressure changes are not occurring in the zones above the Eau Claire confining zone.

The use of Schlumberger's Reservoir Saturation Tool (RST) to monitor the presence or absence of CO_2 in the reservoir has proven to be very successful. The upper boundary of CO_2 can be readily identified in CCS#1 and VW#1. RST will be used in the ICCS project as an integral input for plume tracking, model calibrations, and mechanical integrity verifications. The use of RST as a CO_2 monitoring tool has been described by Butsch and Malkewicz in their poster presented at the 2010 NETL Annual Conference, held in Pittsburgh, PA. 10-13 May 2010. Enhanced Oil Recovery projects have also utilized RST as a viable method for monitoring carbon dioxide floods (Al-Aryani et al, 2011).

As with the Illinois Basin – Decatur Project (IBDP), a combination of time-lapse seismic monitoring technologies will be used to image the CO_2 plume as the project progresses. The primary objective of time-lapse seismic surveys is to monitor qualitative changes in a formation that occur as a result of fluid injection or production.

Rock properties, such as the bulk modulus and density, of a formation change as CO_2 is injected into the formation. In turn, changes to the bulk modulus and density affect measureable seismic parameters like P-wave velocity (V_P) and S-wave velocity (V_S). Supercritical CO_2 is as much as 15 times more compressible than brine (White et al., 2004). Injecting supercritical CO_2 into a formation will decrease the bulk density of the formation and will result in an observable decrease in V_P as well as potentially large impedance contrasts at the injection interval (Couëslan, 2007 and Arts and Winthaegen, 2005). Active time-lapse seismic surveys aim to record these changes.

In the early stages of injection, time-lapse 3D vertical seismic profiles (VSPs) will likely be used to image the developing CO_2 plume. The 3D VSPs will be acquired in GM#2, which is immediately to the northwest of the proposed site of the new injection well (CCS#2). 3D VSPs are an attractive alternative to 3D surface seismic surveys, as they have smaller acquisition footprints that are less disruptive to the surrounding community and cost less to acquire. Time-lapse 3D VSPs have been used successfully to monitor injection and production operations in both on- and offshore environments (Wu et al., 2011 and O'Brien et al., 2004). In particular, time-lapse 3D VSPs were used as a primary monitoring technology to monitor injected CO_2 at the Monell CO_2 EOR pilot project in Wyoming (O'Brien et al., 2004).

Time-lapse 3D surface seismic surveys are now widely used to monitor oil and gas operations around the world. With respect to CO_2 storage projects, the most well-known projects are the Sleipner Project in the Norwegian North Sea and IEA GHG Weyburn-Midale Project in Saskatchewan, Canada (White et al., 2004 and Chadwick et al., 2010). Both of these projects have been injecting CO_2 for storage or EOR for over a decade and time-lapse surface seismic data has been used to image the developing CO_2 plume from an early stage.

In the case of IBDP, the 3D VSP data acquired in GM#1 images out to a radius of approximately 2500 ft at the depth of CO_2 injection into the Mt. Simon Sandstone (Figure 1). A similar imaging aperture is expected from any 3D VSPs acquired in GM#2, as this well will be drilled to a similar depth of 3500 ft and the geology is fairly flat between the two locations. Time-lapse 3D VSPs acquired in GM#2 will be able to monitor the plume related to CCS#2 within the 2,500 ft radius. The acquisition footprint of the 3D VSPs acquired in GM#2 will cover an area similar to the IBDP 3D VSP surveys; however, they will likely use a smaller source spacing based on the lessons learned from IBDP. Current plans are to use a retrievable tool to acquire the 3D VSP surveys in GM#2 rather than using a cemented permanent geophone array.

At the end of the injection period, either a series of 2D surface seismic lines or a final time-lapse 3D surface seismic survey may be utilized to image the final plume. It is expected that the monitoring, verification, and accounting (MVA) data collected over the course of injection will assist in making a final decision on the type of surface seismic survey. For instance, a final surface seismic survey may be needed if the CO_2 plume migrates beyond the imaging aperture of the 3D VSP data.

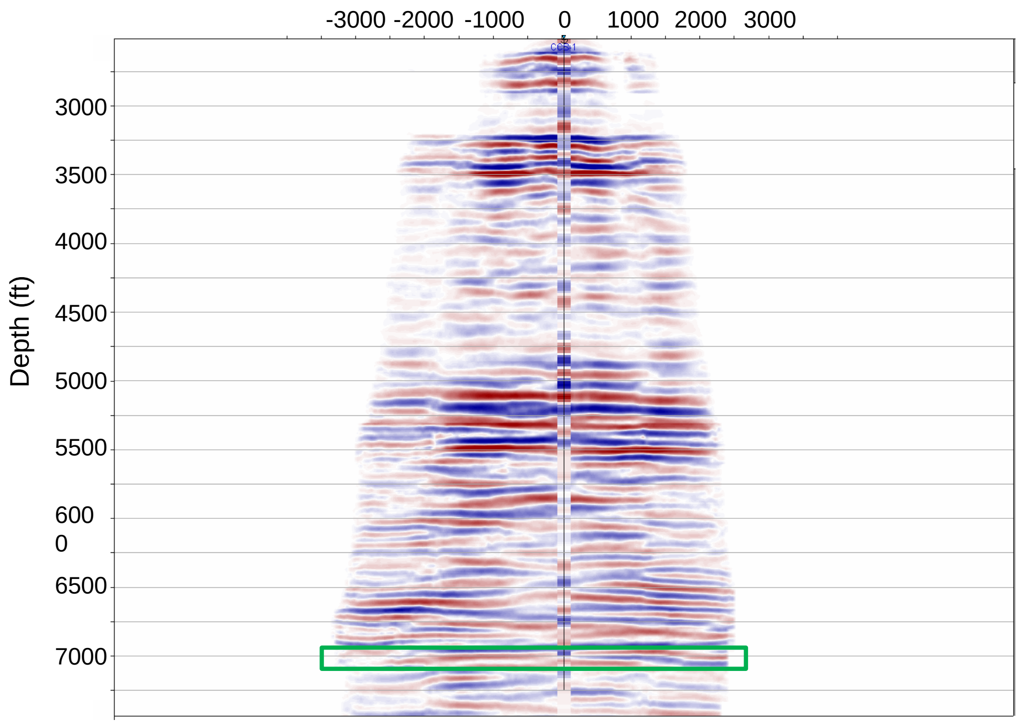

Figure 1: A 3D VSP image from IBDP. The 3D VSP images out to a radius of approximately 2500 ft at the depth of injection (green box). Courtesy of MGSC.

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6A.2.6 Surface Air and Soil Gas Monitoring

Potential Risks to USDW

Based on the injection zone depth within the Mt. Simon, the thickness of the Eau Claire Formation confining unit, and the presence of multiple secondary seals, a scenario where CO_2 comes in direct contact with the site's USDW appears highly improbable. However, to assure that groundwater resources are adequately protected, a groundwater monitoring program will be conducted at the site. The lowermost USDW is not expected to be vulnerable to contamination resulting from the injection of CO_2 into the Mt Simon Sandstone. This is in part due to the presence of multiple hydrologic seals that are barriers to upward fluid movement. Within the Illinois Basin, thick shale units function as significant regional seals. These are the Devonian-age New Albany Shale, Ordovician age Maquoketa Formation, and the Cambrian-age Eau Claire Formation. There are also many minor, thinner Mississippian- and Pennsylvanian-age shale beds that form seals for known hydrocarbon traps within the basin. Regarding overlying seal(s) integrity, all three significant seals are laterally extensive and appear, from subsurface wireline correlations, to be continuous within a 100-mile radius of the test site.

Another important detail is the fact that the lowermost seal, the Eau Claire, has no known penetrations within a 17-mile radius surrounding the site with the exception of the two sequestration-related wells at the IBDP site (CCS #1 and Verification Well #1), both of which are constructed to UIC Class VI specifications. Because the IBDP wells were recently constructed with special materials meeting UIC Class VI specifications (i.e. chrome casing and CO_2 resistant cement), their integrity is well known and documented.

The Illinois Basin has the largest number of successful natural gas storage fields in water bearing formations in the United States. These gas storage fields provide important analogs that can be used to analyze the potential for CO_2 sequestration. These analogs illustrate long-term seal integrity, injection capability, storage capacity, and reservoir continuity in the north-central and central Illinois Basin at comparable depths. Nearly 50 years of successful natural gas storage in the Mt. Simon Sandstone strongly indicated that this saline reservoir and overlying seals should provide successful containment for CO_2 sequestration.

Gas storage projects in the Illinois Basin all confirm that the Eau Claire is an effective seal in the northern and central portions of the Basin. Core analysis data from the Manlove Gas Storage Field, 45 miles to the northeast of the proposed site, show that the Eau Claire shale intervals have vertical and horizontal permeability less than 0.1 mD.

Regional cross sections in the central part of Illinois show that the Eau Claire Formation, the primary seal, is a laterally persistent shale interval above the Mt. Simon that is expected to provide a good seal. Drilling at the IBDP site shows that the Eau Claire should be approximately 500 feet thick at the IL-ICCS site (reference Section 2.5 of this application). As discussed in Section 2.5, the IL-ICCS site should have approximately 200 feet of sealing shale in the Eau Claire Formation directly above the Mt. Simon Sandstone.

The database of UIC wells with core from the Eau Claire was also used to derive seal qualities. This database shows that the Eau Claire's median permeability is 0.000026 mD and median porosity is 4.7%. At the Ancona Gas Storage Field, located 80 miles to the north of the proposed ADM site, cores were obtained through 414 feet of the Eau Claire, and 110 analyses were performed on a foot-by-foot basis on the recovered core. Most vertical permeability analyses showed values of <0.001 to 0.001 mD. Only five analyses were in the range of 0.100 to 0.871 mD, the latter being the maximum value in the data set. Thus, even the more permeable beds in the Eau Claire Formation are expected to be relatively tight and tend to act as sealing lithologies.

There are no mapped regional faults and fractures within a 25-mile radius of the ADM site. New 2D seismic reflection data did not detect any faults or adverse geologic structures in the vicinity of the proposed well site (Section 2.2). The drilling of the injection well will yield data such as time-to-depth conversions, and will be used to design and execute a comprehensive 3D seismic data volume to further ensure that no seismically resolvable faults and fractures pose a threat to the integrity of the injection site. Moreover, there are no known unplugged, abandoned wells that penetrate the confining layer (Section 5.5).

Finally, it must be noted that a portion of the injected CO_2 will be converted to carbonic acid upon contact with the brine in the injection formation, but this is not expected to significantly impact the formation lithology. This is due to brine's pH being maintained above 2.0 because of pH-buffering reactions that will occur between the acidified brine and feldspar minerals within the Mt. Simon Sandstone.

6A.2.6.2 Surface Air Monitoring Plan

Due to the limited risk of USDW endangerment by CO_2 migration as discussed in Section 6A.2.6.1, and similarly the limited risk of migration to the atmosphere, surface air monitoring is not proposed for this permit.

6A.2.6.3 Soil Gas Monitoring Plan

Due to the limited risk of USDW endangerment by CO_2 migration as discussed in Section 6A.2.6.1, and similarly the limited risk of migration to the soil, soil gas monitoring is not proposed for this permit.

6A.2.7 Periodic Review

The testing and monitoring plan shall be periodically reviewed to incorporate collected monitoring and operational data. No less frequently than every 5 years, the most recent area of review shall be reevaluated and based on this review, an amended testing and monitoring plan, or demonstration that no revision is necessary, shall be submitted to the permitting agency. Any amendments to the testing and monitoring plan approved by the permitting agency, will be incorporated into the permit, and will subject to the permit modification requirements as appropriate. Amended plans or demonstrations shall be submitted to the permitting agency:

(1) Within one year of an area of review re-evaluation; or

(2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the permitting agency; or

(3) When required by the permitting agency.

Figure 6A-2: Thickness of the upper Glasford aquifer (modified from Larson et al., 2003). The IL-ICCS project site within T17N, R3E is shown in red.

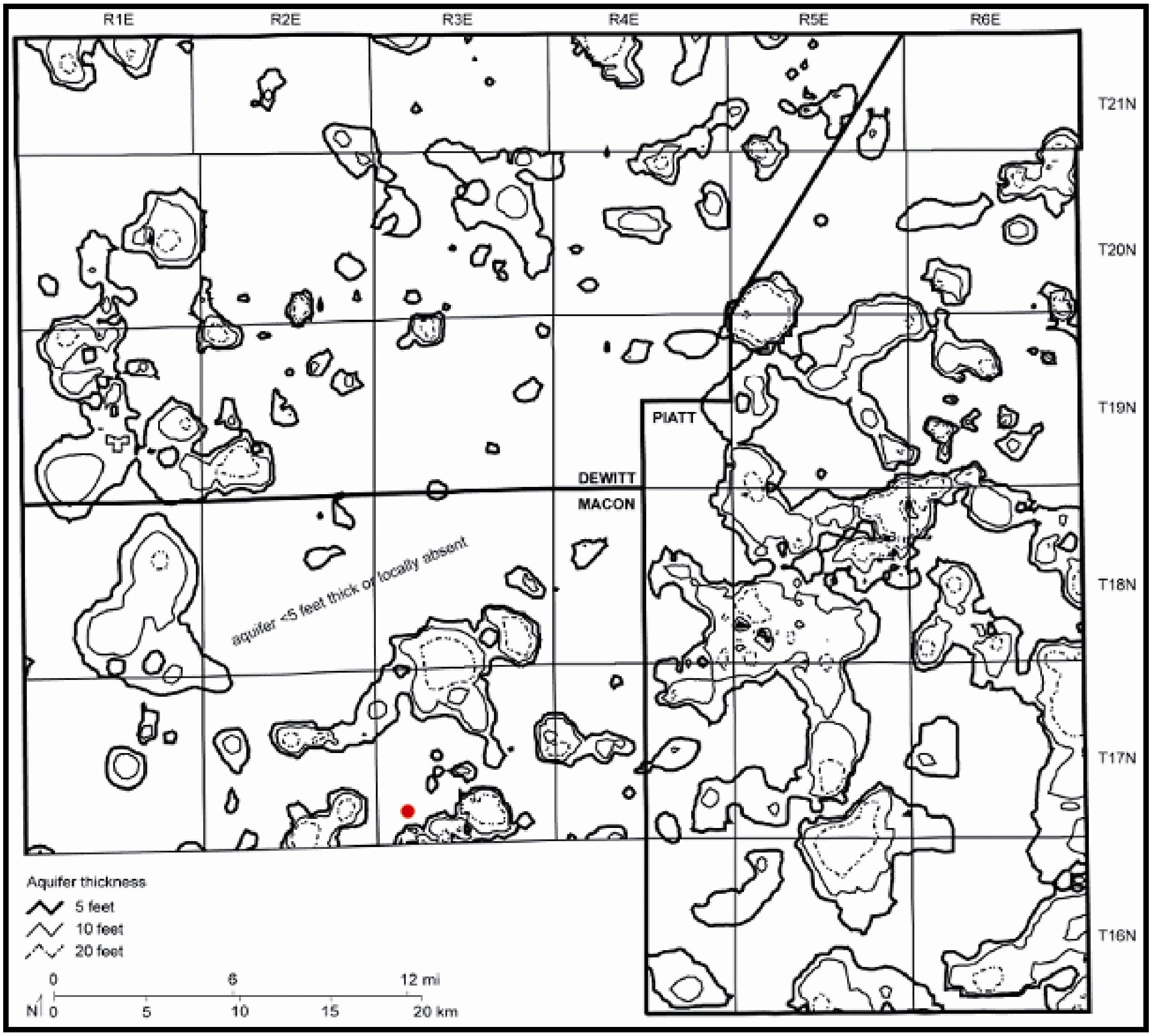
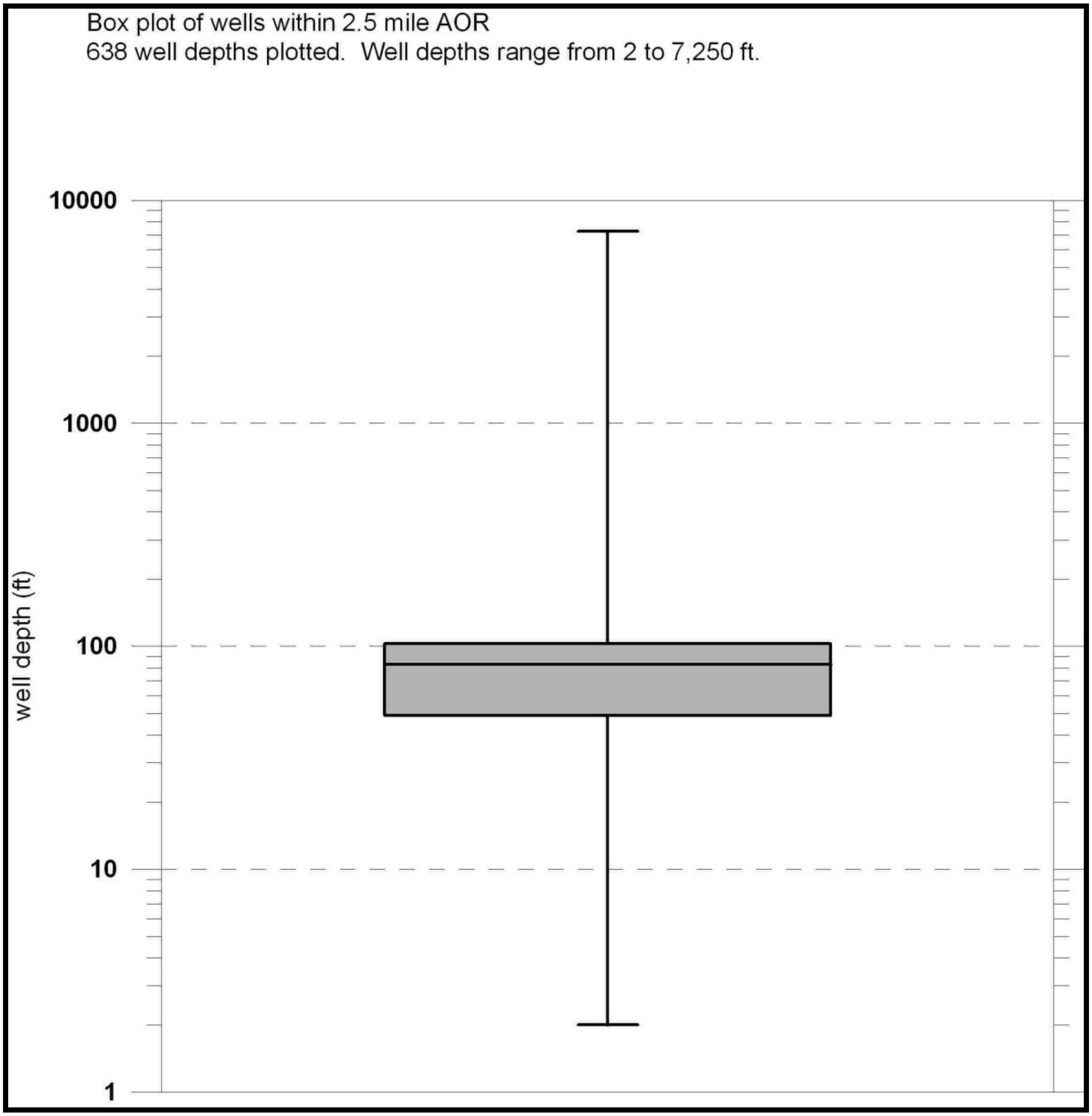


Figure 6A-3: Box plot of the water well depths within 2.5 mile radius of injection well site.



The box plot shows the distribution of the well depths. The bottom of the box marks the 25th percentile, the middle marks the median (50%) and the top marks the 75th percentile. The long whiskers mark the minimum and maximum. This graph was generated using 638 data points.

Figure 6A-4: Depth to the upper Glasford aquifer (modified from Larson et al., 2003). The IL-ICCS project site within T17N, R3E is shown in red.

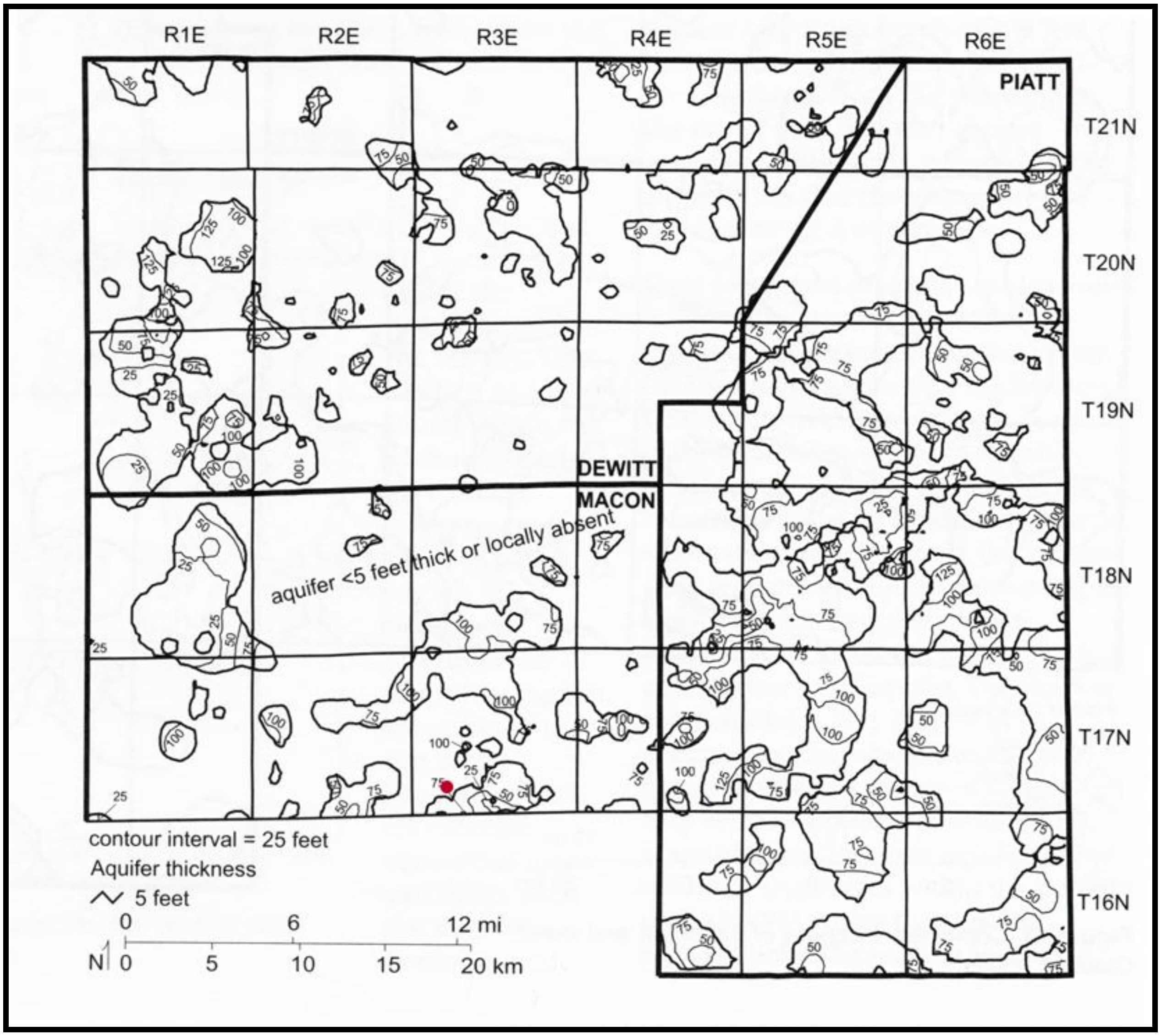


Figure 6A-5: Proposed locations of the IL-ICCS injection well and USDW monitoring wells.

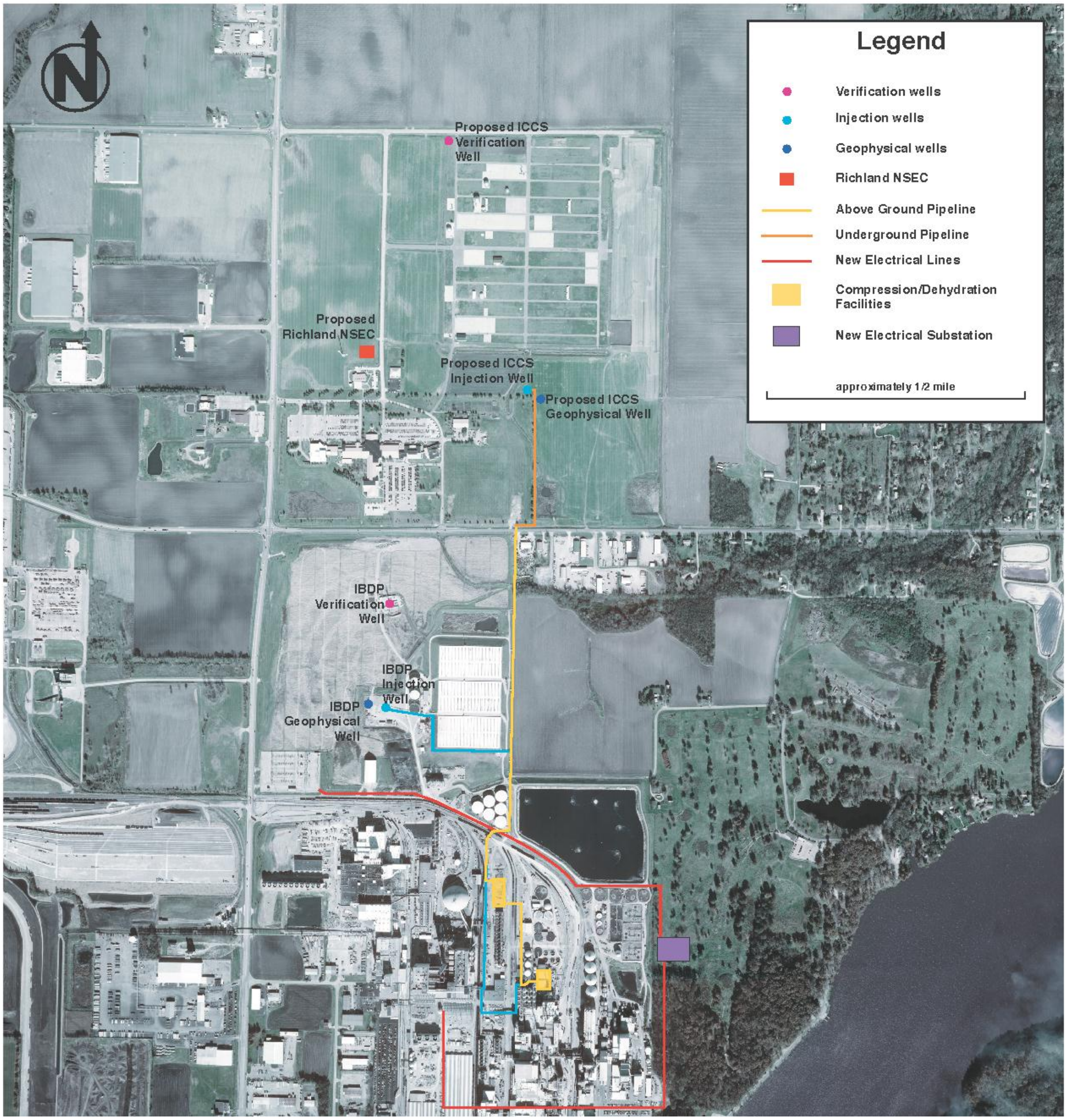
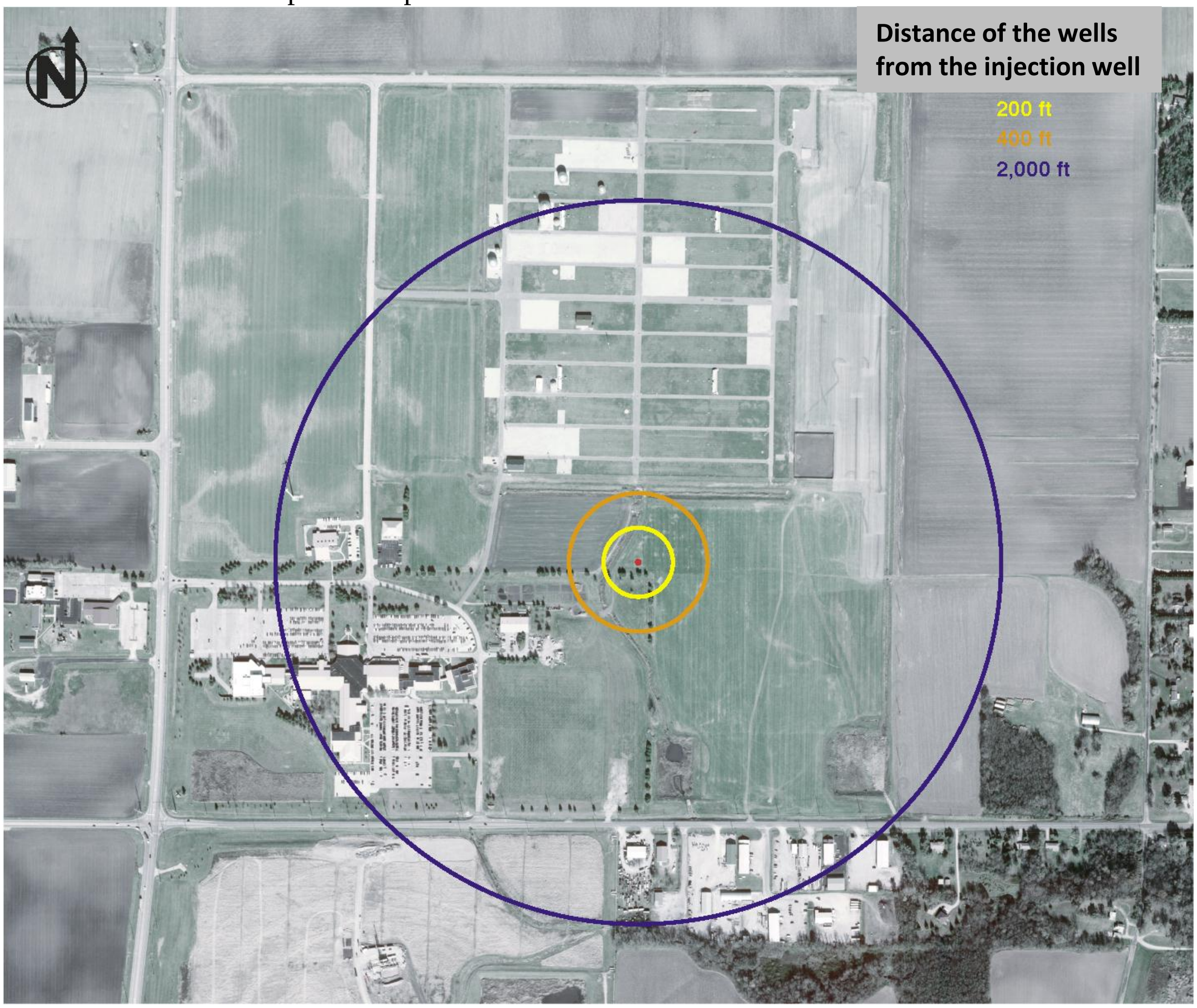


Figure 6A-6: Shallow Groundwater Well Locations.

Shallow ground water wells will include two wells within 200 feet of the injection well, one additional well within 400 feet, and a fourth compliance well within 2000 feet of the CCS #2 injection well. The precise locations of these wells are yet to be determined and will be documented in the completion report.



6A.3 Mechanical Integrity Tests During Service Life of Well

6A.3.1 Continuous Monitoring of Annular Pressure

To verify the "absence of significant leaks," the surface injection pressure, and the casing-tubing annulus pressure will be continuously monitored and recorded.

The following procedures will be used to limit the potential for any unpermitted fluid movement into or out of the annulus (see Section 3A.7.5):

i. The annulus between the tubing and the long string of casing shall be filled with brine. The brine will have a specific gravity of 1.25 and a density of 10.5 lbs/gal. The hydrostatic gradient is 0.546 psi/ft. The brine will contain a corrosion inhibitor.
ii. The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) at all times.
iii. The pressure within the annular space, over the interval above the packer to the confining layer, shall be greater than the pressure of the injection zone formation at all times.
iv. The pressure in the annular space directly above the packer shall be maintained at least 100 psi higher than the adjacent tubing pressure during injection. This does not include start-up and shutdown periods.

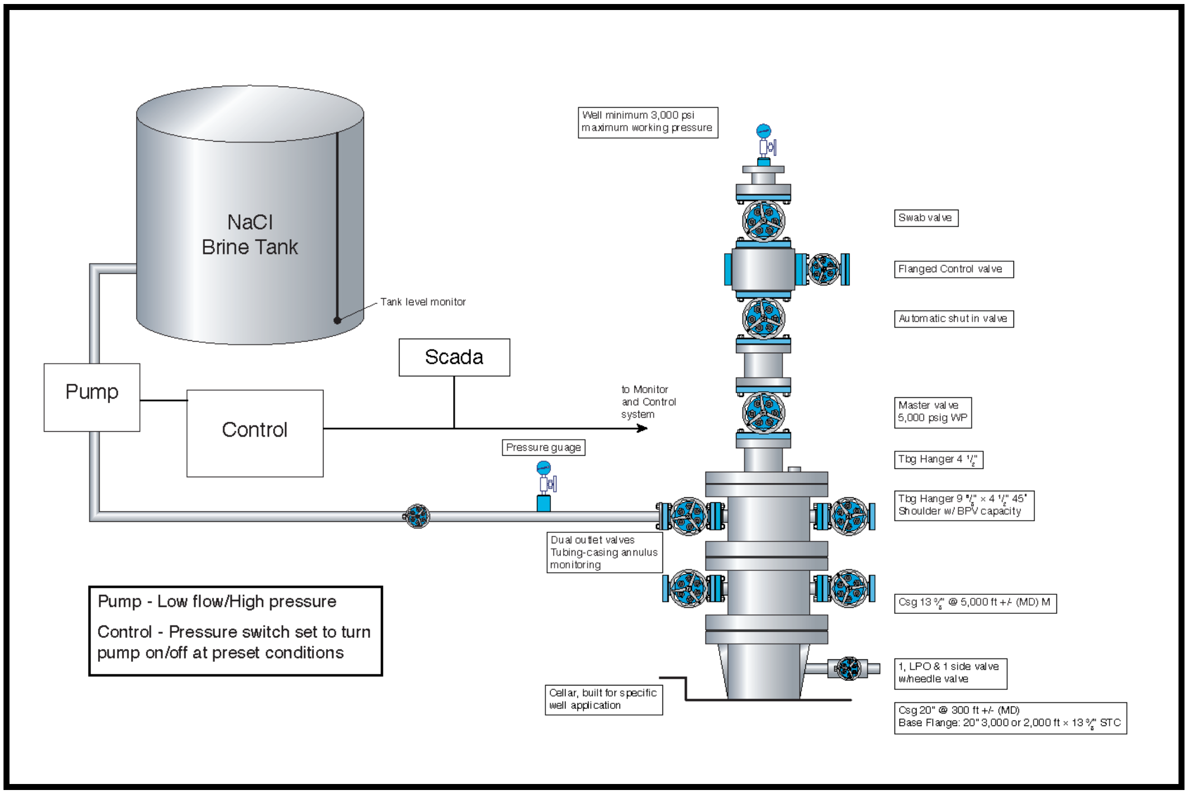
Figure 6A-7 shows the injection well annulus protection system. The annular monitoring system will consist of a continuous annular pressure gauge, a brine water storage reservoir, a low-volume/high-pressure pump, a control box, fluid volume measurement device, fluid, and electrical connections. The control box will receive pressure data from an annular pressure gauge and will be programmed to operate the pump as needed to maintain approximately 400 psi (or greater) on the annulus. A means to monitor the volume of fluid pumped into the annulus will be incorporated into the system by use of a tank fluid level gauge, flow meter, pump stroke counter or other appropriate devices.

The annulus pump will be a General Pump Co. Model 1321 (or similar device) triplex pump rated to 2,100 psi and a flow rate of 5.5 gpm. The pump will be powered by a 3.0 hp, 110/220V electric motor. Pressure will be monitored by the ADM control system gauges. The pump will be controlled by two pressure switches one for low pressure to engage the pump and the other for high pressure to shut the pump down. Anticipated range on the switches would be 400 psi or higher for the low pressure set point and 500 psi or higher for the high pressure set point. Annulus pressure will be monitored at the ADM data control system. A brine storage tank will be connected to the suction inlet of the pump. A hydrostatic tank level gauge will be installed in the brine storage tank with data fed into the ADM monitoring system. The brine in the storage tank will be the same brine as in the annulus. Any changes to the composition of annular fluid shall be reported in the next report submitted to the permitting agency.

As noted in Section 6A.2.2.2, if system communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every four hours or twice per shift for both wellhead surface pressure and annulus pressure, and record hard copies of the data until communication is restored. An example of a form for maintaining the record is included in Figure 6A-1.

Average annular pressure and fluid volumes changes will be recorded daily and reported to the permitting agency as required.

Figure 6A-7: The annular monitoring system general layout.



6A.3.2 Annual Testing

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded at least annually across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided.

Internal Mechanical Integrity will be demonstrated through the continuous monitoring of the annular system as described in the preceding section.

6A.3.3 Other Available Testing (If Conditions Warrant)

If required due to anomalous temperature data and to verify the "absence of significant fluid movement," a Pulsed Neutron Capture / Sigma log (i.e. Schlumberger's Reservoir Saturation Tool, or RST), can be run in the injection well from the base of the injection interval through the seal and across the porous zones above the seal. An initial RST will also be run before CO_2 injection to establish a good pre-CO_2 baseline to compare the post-CO_2 logging runs. The RST cased hole can be run through tubing such that the tubing and packer do not need to be removed during logging. The RST can also provide Sigma measurement through multiple strings of casing and tubing.

The logging tools can enter the wellbore through a lubricator at the surface, so it is not necessary to kill the well with another liquid. The tubing design is such that there are no restrictions so that the appropriate cased hole logging tools (e.g. RST, Temperature, Pressure) can pass through the tubing and log the near wellbore environment behind the casing.

Testing procedures can be found in Appendix G. Annular pressure will be measured at the surface continuously to check for increases or decreases in pressure.

Details of Schlumberger's version of these tools are described below:

<u>Pulsed Neutron Capture Logging</u>

Reservoir Saturation Tool (RST) - Designed for reservoir complexity

Within the last decade, nearly every aspect of reservoir management has grown in complexity. What once was the exception is now routine: multiple-tubing and gravel pack completions, secondary and tertiary recovery, highly deviated wellbores, and three-phase production environments. The RSTPro* Reservoir Saturation Tool helps manage complexity by delivering reliable, accurate data. Run on the PS Platform string, with its suite of cased hole reservoir evaluation and production logging services, the RSTPro tool uses pulsed neutron techniques to determine reservoir saturation, lithology, porosity, and borehole fluid profiles. This information is used to identify bypassed hydrocarbons, evaluate and monitor reserves in mixed salinity and gas environments, perform formation evaluation behind casing, and diagnose three-phase flow independently of well deviation. Pulsed neutron technology.

An electronic generator in the RSTPro tool emits high-energy (14-meV) neutrons in precisely controlled bursts. A neutron interacts with surrounding nuclei, losing energy until it is captured. In many of these interactions, the nucleus emits one or more gamma rays of characteristic energy, which are detected in the tool by two high-efficiency GSO scintillators. High-speed digital signal electronics process and record both the gamma ray energy and its time of arrival relative to the start of the neutron burst. Exclusive spectral analysis algorithms transform the gamma ray energy and time data into concentrations of elements (relative elemental yields).

Formation sigma, porosity, and borehole salinity
In sigma mode, the RSTPro tool measures formation sigma, porosity, and borehole salinity using an optimized Dual-Burst* thermal decay time sequence. The two principal applications of this measurement are saturation evaluation, which relies on measurement accuracy, and time-lapse monitoring, where sensitivity is determined by measurement repeatability. A new degree of accuracy in the formation sigma measurement is achieved by combining high-fidelity environmental correction with an extensive laboratory characterization database. The accuracy of RSTPro formation sigma is 0.22 cu for characterized environments and has been verified in the Callisto and American Petroleum Institute industry-standard formations. Formation porosity and borehole salinity are either computed in the same pass or input by the user. Exceptional measurement repeatability makes the RSTPro tool more sensitive to minute changes in reservoir saturation during time-lapse monitoring. The gains in repeatability and tool stability are the result of higher neutron output and sensor regulation loops. At the typical logging speed of 900 ft/hr [275 m/hr] for time-lapse monitoring, RSTPro repeatability is 0.21 cu.

Multifinger Imaging Tool
The PS Platform* Multifinger Imaging Tool (PMIT) is a multifinger caliper tool that makes highly accurate radial measurements of the internal diameter of the tubing string. The tool is available in three sizes to address a wide range of through-tubing and casing size applications. The tool deploys an array of hard-surfaced fingers, which accurately monitor the inner pipe wall. Eccentricity effects are minimized by equal azimuthal spacing of the fingers and a special processing algorithm, and the PMIT-B tool incorporates powerful motorized centralizers to ensure effective centering force even in highly deviated intervals. The inclinometer in the tool provides information on well deviation and tool rotation. The PMIT-C tool can be fitted with special extended fingers for logging large-diameter boreholes.

Applications
- Identification and quantification of corrosion damage
- Identification of scale, wax, and solids accumulation
- Monitoring of anticorrosion systems
- Location of mechanical damage
- Evaluation of corrosion increase through periodic logs
- Determination of absolute inside diameter (ID)

6A.3.4 Ambient Pressure Monitoring

A pressure falloff test can be conducted if required during injection to calculate the ambient average reservoir pressure. At least one pressure fall-off test shall be performed every 5 years in accordance with 40 CFR 146.90(f). The availability of pressure data from Verification Well #2 and Verification Well #1 (IBDP Project) will provide alternative sources of pressure monitoring of the injection zone. At a minimum, a planned pressure falloff test will be preceded by one week of continuous CO_2 injection at relatively constant rate. The well will be shut-in for at least four days or longer until adequate pressure transient data are measured and recorded to calculate the average pressure. These data will be measured using a surface readout downhole gauge so a real-time decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line).

Pressure Falloff Test Procedure

A pressure falloff test has a period of injection followed by a period of no-injection or shut-in.

Normal injection using the stream of CO_2 captured from the ADM facility will be used during the injection period preceding the shut-in portion of the falloff tests. The normal injection rate is estimated to be 3,000 MT/day (the last 3 years of the planned 5-year injection period). Prior to the falloff test this rate will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased. Injection will have occurred for 10-11 months prior to this test, but there may have been injection interruptions due to operations or testing. At a minimum, one week of relatively continuous injection will precede the shut-in portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre-shut-in injection period and subsequent analysis. This data will be measured using a surface readout downhole gauge so a final decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line).

To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection compression facility operator. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at five second intervals or less for the entire test. The shut-in period of the falloff test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Because surface readout gauges will be used, the shut-in duration can be determined in real-time. A report containing the pressure falloff data and interpretation of the reservoir ambient pressure will be submitted to the permitting agency within 90 days of the test. Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure fall off test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (.5% accuracy across full range). Wellhead pressure gauge range will be 0-4,000 psi. Downhole gauge range will be 0- 10,000 psi.

6A.3.5 Corrosion Monitoring Plan

In order to monitor the corrosion potential of materials that will come in contact with the carbon dioxide stream, the following plan has been developed.

Sample Description

Samples of material used in the construction of the compression equipment, pipeline and injection well which come into contact with the CO_2 stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 6A-2 below. Each coupon will be weighed, measured, and photographed prior to initial exposure (see Sample Monitoring section for measurement data).

Table 6A-2: List of Equipment Coupon with Material of Construction.

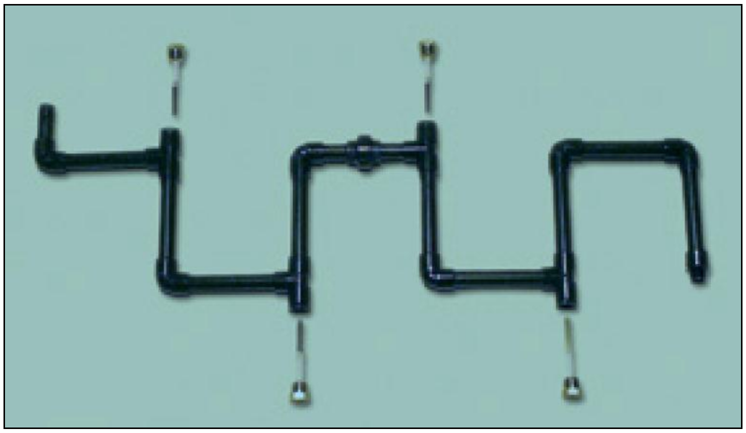
Equipment Coupon	**Material of Construction**
Pipeline	CS XPI5L-X52
Long String Casing	Chrome alloy
Injection Tubing	Chrome alloy
PS3 Mandrel	Chrome alloy
Wellhead	Chrome alloy
Packers 1	Chrome alloy
Compression Components	316L SS

Sample Exposure

Each sample will be attached to an individual holder (Figure 6A-8) and then inserted in a flow-through pipe arrangement (Figure 6A-9). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (i.e., at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO_2 past this point; therefore this location will provide representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal.

Figure 6A-8. Coupon Holder

Figure 6A-9. Flow-Through Pipe Arrangement



Sample Monitoring

The samples will be visually inspected and monitored on a quarterly basis for loss of mass, thickness, cracking, pitting, or other signs of corrosion. The sample holder will be removed from the CO_2 stream, and the samples will be removed from the holder for examination and measurements. Each coupon will be photographed and then be evaluated with the following precisions: Dimensional: 0.0001 inches; Mass: 0.0001 grams. The coupons will then be examined microscopically at a minimum of 10x power. Weights of the samples will be compared with original weights to determine if there is any weight gain or loss that would indicate degradation.

Reporting

Dimensional and mass data, along with a calculated corrosion rate (in mils/yr), will be submitted with the facility's regular operating report following the analysis.

6A.4 Contingency Plan for Well Failure or Shut In

In addition to routine or scheduled maintenance and certain system testing procedures, injection will be shut down under the following conditions (see Appendix H for Emergency and Remedial Response Plan required under 40 CFR 146.94):

- Wellhead injection pressure reaches the automatic shutdown pressure of 2,380 psig. Fracture gradient was determined to be 0.715 psi per foot, or, for mid-perforation depth of 7,025 feet, the fracturing pressure would be 5,023 psi. Using a CO_2 density of 47.31 lbs/cf with a hydrostatic gradient of 0.3285 psi/ft during injection, a wellhead pressure of 2,714 psig would be required to fracture the formation with a CO_2 of this density. The compression system has been designed and constructed for pressures up to 2,500 psig. The pipeline system has been designed and constructed for working pressure up to 2,500 psig, based on the ASME code mandated stress analysis of the pipeline components. Therefore, the surface equipment is the pressure limitation and not formation fracturing pressure.
- Injection mass flow will be continuously monitored for instantaneous flow rate and total mass injected. At no time will a mass flow rate greater than 3,300 MT be injected in a "day". The electronic control system will be configured to shut down the injection system if the mass flow rate exceeds 3,300 MT per day for a set period of time (but in no case greater than 8 hours) or if the total mass injected for the "day" equals 3,300 MT. Such an arrangement will prevent an overly-high instantaneous injection rate from continuing unabated, while also ensuring that total mass injected does not exceed permit limits. Also, it is requested that a day be defined as the period from 6:00 a.m. to 5:59 a.m. to accommodate the data archiving system in place at the Decatur Plant.

- Surface temperature varies outside the permitted range.

- Failure to maintain the tubing/casing annulus pressure (measured at the surface) at greater or equal to 400 psig.

- Failure to maintain sufficient surface annular pressure (estimated at 400 to 500 psig but may vary according to injection pressures) to maintain a minimum differential of 100 psi between the downhole annular pressure and the adjacent tubing pressure just above the packer. (The annular pressure is to be higher than the tubing pressure.) Pressures are to be calculated from surface gauge readings.

- There is reason to suspect that the injection well or cap rock integrity has been compromised via one or more of the following:

a. Failure of mechanical integrity testing as defined in the approved permit indicates CO_2 migration above the cap rock. These tests include annular pressure tests, time lapse sigma logging and temperature surveys.
b. Lowermost USDW groundwater compliance monitoring shows a statistically significant change in groundwater quality that is a direct result of CO_2 injection. Groundwater monitoring procedures shall be defined in the approved permit.

Above listed limits apply to the injection of CO_2 except during startup, testing and shutdown periods (as defined by the approved permit). At no time will injection pressures exceed the pressure that could initiate fracturing of the injection zone and/or cap rock.

If a shutdown occurs by any of the control devices, an immediate investigation will be conducted. The condition will be rectified or faulty component repaired and system will be restarted.

If the system is shutdown due to sub-surface or wellbore related issues, an investigation will be undertaken as to the cause of the event that initiated the shutdown. A series of steps can be taken to address the loss of mechanical or wellbore integrity and determine if the loss is due to the packer system or the tubing by isolating the tubing above the packer. RST logs may be run to determine well bore integrity status. In the event of a shutdown due to a subsurface related issue, adequate time will be required to develop a workover plan and to mobilize the required equipment. If a major workover is required, the well can be sealed off by placing a blanking plug in the tailpipe below the packer, and the well loaded with kill-weight brine while plans are developed as to how to best approach the workover.

6A.4.1 Persons Designated to Oversee Well Operations

A site-specific list of persons designated to oversee well operations in the event of an emergency shall be developed and maintained during the life of the project.

6A.5 Quality Assurance Plan

Data collected by the operator for testing and monitoring of the Class VI injection well will be subject to verification by an independent laboratory or, if compiled in-house, will be subject to verification using in-house quality assurance procedures.

Testing and monitoring data to be submitted to the permitting agency will be reviewed by the operator prior to submission. Any data inaccuracies will be noted and checked to determine the error source (e.g. monitoring equipment malfunction, data entry error, lab reporting error, etc.) and correct the error source as soon as possible.

6A.6 Reporting Requirements

This section is provided to satisfy the requirements of 40 CFR 146.90.

The operator shall provide required reports to the permitting agency in an approved electronic format.

Required reports will include the following;

(1) Semi-annual reports
  a. Quarterly carbon dioxide stream characteristics (physical, chemical, other);
  b. Monthly average, maximum, and minimum values for:
    i. Injection pressure;
    ii. Flow rate and mass;
    iii. Annular pressure;
  c. Any event(s) that exceed operating parameters for annular pressure or injection pressure;
  d. Any event(s) which trigger a shut-off device;
  e. Monthly volume and/or mass of carbon dioxide injected over the reporting period;
  f. Cumulative volume of carbon dioxide injected over the project life;
  g. Monthly annulus fluid volume added to the injection well.

(2) Results to be reported within 30 days:
  a. Periodic tests of mechanical integrity;
  b. Any well workover;
  c. Any other test of the injection well performed, if required by the permitting agency.

(3) Information to be reported within 24 hours of occurring:
  a. Any evidence that the carbon dioxide stream or associated pressure front has or may cause endangerment to a USDW;
  b. Any non-compliance with permit condition(s), or malfunction of the injection system, that may cause fluid migration to a USDW;
  c. Any triggering of a shut-off system;
  d. Any failure to maintain mechanical integrity;
  e. Any uncontrolled release of carbon dioxide to the atmosphere.

(4) Notification to be provided at least 30 days in advance:
  a. Any planned well workover;
  b. Any planned stimulation activities (other than stimulation for pre-operation formation testing)
  c. Any other planned test of the injection well.

Records will be retained for at least 10 years following site closure.